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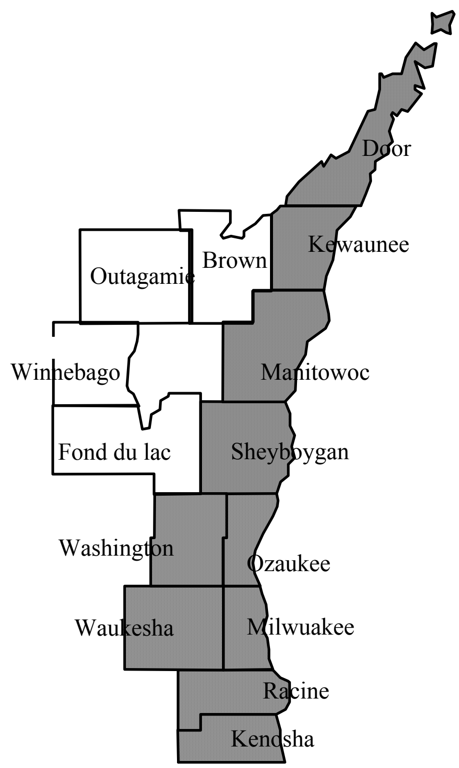
APPENDIX SIX
EGU Inventory Methodology

Overview

Electric utility emissions of NOx and VOC are projected for Manitowoc County, 1-hour ozone non-attainment counties, and contiguous attainment counties based on a system-wide approach to meeting electric demand. The larger region includes generation capacity in the attainment counties of Brown, Outagamie, Winnebago, and Fond du Lac. Counties not included in the analysis but adjacent to the non-attainment area do not have electric generating facilities.

Designated Region for Electric Utility Sector Analysis



Theoretically, additional generation units in an even larger region are available to aid in meeting non-attainment area electricity needs. However, a primary aim of the analysis is to establish a conservatively high, but reasonable estimate of electric utility sector emissions for the non-attainment counties. Therefore the generation units and resulting analysis region assumes core generation remains in the non-attainment areas but accounts for operation of company resources and servicing of electric territories. In keeping with a conservative approach the analysis further assumes that growth beyond existing capacity is met by installing coal fired generation in lieu of other less emitting options such as combined cycle plants.

Calculation of Emissions

The NOx and VOC emission budget for electric generating units (EGUs) consists of 1999 and 2002 emissions and projections for 2007, 2010, 2015, and 2018. The facilities captured in the electric utility sector include public, private, and municipal utilities designated by the 4900 SIC code series. The emissions budget includes not only the primary electric generation units but also any other emitting process operating at the facility. The emission units are those identified in the Wisconsin Air Emissions Inventory (AEI) and periodic inventory.

1999 and 2002 Historic Emissions

The majority of NOx emitted in 1999 and 2002 by the EGU sector is determined using Acid Rain program continuous emission data(1). The Acid Rain program applies to units feeding generators of 25 MW or greater including coal-fired boilers, combine cycle systems, and combustion turbines. The Acid Rain units account for over 96% of NOx emitted by EGU facilities in the analysis region.

EPA summarized Acid Rain data to yield the amount of NOx emitted by each emission unit during the five-month ozone season. An average daily emission is obtained by dividing the resulting NOx mass value by the 153 days in the ozone season. This approach provides a close approximation of an average summer day and a consistent basis for evaluating the relative change in utility sector NOx emissions. This method is preferred as it is straightforward, transparent, and based on readily available, quality assured EPA data.

The historic mass of NOx emitted by the balance of units not subject to Acid Rain requirements is derived using Wisconsin Air Emissions Inventory (AEI) data. This applies to the two smallest coal fired boilers at Manitowoc Public Utility, four combustion turbines at the Germantown facility, several small municipal facilities, and the non-generating processes at all EGU facilities. The annual emissions for each unit are apportioned to a summer three-month value using weighted second and third quarter process activity reported in the AEI. This value is then divided by 92 days to yield the average tons of NOx emitted per summer day.

The VOC emitted by all EGU facility processes including generating and non-generating units is determined using AEI data. The annual VOC emissions in the AEI are proportioned to the summer day by the same methodology used for NOx emitted by non-Acid Rain units. The AEI data yields the best estimate of daily summer VOC emissions for all units and processes since the Acid Rain program does not require monitoring and reporting of VOC emissions.

Utility Sector Growth Rate

The analysis projects EGU emissions as a function of growth in electricity consumption and demand during the summer period.

The Wisconsin Public Service Commission (PSC) estimates that annual statewide electric consumption will increase between 2.1% to 2.3% per year through 2010[2]. And electricity consumption during the summer months will grow at a higher rate of 2.5% per year.

Another source of information is historic data for electric consumption and demand of four utilities serving eastern Wisconsin[3]. The service territories covered by these four utilities coincide closely with the area designated in this analysis. From this data the annual growth rate for total electric consumption is calculated to be 2.5% from 2000 through 2003. For this same period a growth rate of 2.7% is calculated for instantaneous electricity use (peak demand) during the summer months.

Both of the calculated historic growth rates are slightly higher but consistent with the PSC statewide projections. Although not directly calculated from historic data, the growth rate in summer electric consumption would likely be in a range between 2.5% and a maximum 2.7% as represented by growth in summer peak demand. This would appear to indicate a growth rate of 2.6% to 2.7% for the four utility area which agrees well with the PSC projected 2.5% statewide growth rate for summer electricity consumption.

Based on these data sources a 2.7% growth rate in summer electricity consumption is assumed in this analysis. This rate appears to indicate a maximum potential rate that is actually representative of peak demand growth for the area. As such this growth rate yields a conservatively high estimate of average generation and associated emission growth into the future.

Projection of Coal fired and Combined Cycle Emissions

Nitrogen oxide emissions for coal fired and combined cycle EGU units are projected on a unit by unit basis using the 2002 ozone season heat input grown by the assumed 2.7% growth rate for electricity consumption. The heat input is from Acid Rain program data with the exception of two small non-Acid Rain units at Manitowoc Public Utility. For these two units ozone season data is derived using the AEI data for annual heat input apportioned by quarterly activity to the summer months.

The 2002 heat input of a coal fired or combined cycle unit is grown throughout the analysis timeframe. But once an individual unit reaches maximum capacity the excess calculated heat input is transferred to other existing units as available. The sequence of preference is first to coal fired units owned by the same utility, then to a coal fired unit in the region, then to natural gas combined cycle units in the region. The capacity of several combined cycle facilities currently under construction in the region is also made available in the analysis. Once existing capacity is fully utilized the excess heat input is transferred to an assumed new coal fired unit in the region.

A maximum capacity is determined for each unit based on its nameplate heat input capacity reported in the Wisconsin Air Emission Inventory and by assuming a summer capacity factor. The capacity factors are 80% for boilers < 500 mmbtu/hr; 90% for boilers < 1,000 mmbtu/hr; 95% for boilers > 1000 mmbtu/hr; and 50% for all combined cycle units. Higher capacity factors are used for any one individual unit when demonstrated by historic data.

The mass of summer NOx emissions is then calculated using an appropriate emission factor representative of 2002 acid rain emission data, AEI data, current permit conditions, or upcoming enforceable emission limits. The latter is comprised of NOx emission limits under state rule NR 428 for EGU boilers greater than 500 mmbtu/hr and Federal Consent Decree requirements for boilers owned by We-Energies. The resulting mass of NOx emissions is then further divided by the 153 days in the ozone season to yield the approximate average summer day value.

The amount of Volatile Organic Compounds emitted by a coal fired and combined cycle unit is projected by directly growing the 2002 year emissions. The growth rate coincides with the growth of heat input on a unit-by-unit basis determined for calculating NOx emissions.

Projection of Combustion Turbine Emissions

The projection of combustion turbines is treated separately from combined cycle or coal fired generation. The emissions are grown directly on a unit by unit basis with no limit to capacity. This is a simplified approach that assumes new units will be installed as needed with similar or lower emission rates. The emissions are grown using the assumed 2.7% growth rate in summer electricity consumption.

Associated Processes at EGU Facilities

The NOx and VOC emissions for non-generating processes are projected based on the growth of the electric generating units at that facility. For example, the growth in heat input resulting for coal-fired capacity is applied to the associated processes at the facility. If two different types of units are at one facility (e.g. coal boiler and combustion turbine) the less restrictive growth is applied to the associated processes.

New Capacity Emissions

As stated, once the regional capacity of existing coal fired and combined cycle units is fully utilized the excess grown heat input is transferred to a surrogate new coal fired unit. A review of issued air permits indicate natural gas fired combined cycle units comprises the majority of baseload capacity constructed since 1990. However, this analysis assumes new capacity will be coal fired in order to provide a conservatively high estimate of regional emissions.

The NOx emission rate for a new coal unit is assumed to be 0.07 lbs/mmbtu, representing control with a selective catalytic reactor system. This rate is based on a review of recently approved coal fired unit permit applications in Wisconsin. The assumed VOC emission rate is 0.005 lbs/mmbtu per EPA's AP-42 compilation of air emission factors to correlate with good combustion practices.

Conclusions

The NOx and VOC emissions resulting from the discussed methodology are summarized by county in Table 1. The emissions are compiled to show cumulative emissions for Manitowoc and the immediately upwind Sheboygan County together, the 6 County non-attainment area, the 8 County non-attainment area, and the entire analysis region. The NOx and VOC emissions are summarized by facility in Tables A1 and A2.

VOC Emissions

The analysis indicates VOC emissions will increase on the order of 1 ton per day between 1999 and 2018 in the designated region. The portion of increase in non-attainment counties is approximated to be 0.7 tons per day. The total amount of VOC emitted in 2018 is estimated to be 3.9 tons per day in the non-attainment area and 5.3 tons per day for the entire region.

The small amount of VOC emitted by EGUs and the slight VOC emissions increase reflects the relatively small emission rate for generation combustion processes as compared to other sources of VOC emissions. Even a large increase in electric generation activity would not result in a large change in VOC emissions.

NOx Emissions – 1999 to 2002

The amount of overall NOx emitted in the analysis region decreased by approximately 22 tons per summer day between 1999 and 2002. This value is the balance of nearly 24 tons per day reduction in the non-attainment counties coupled with a slight increase in the adjacent counties.

It is significant to Manitowoc County that 22 tons per day reduction took place immediately upwind in Sheboygan County. The reduction is the result of permanent equipment modifications at the Edgewater coal fired plant specifically for efficiency improvement and NOx control. This equates to a 40% reduction in NOx emissions between 1999 and 2002 for the Manitowoc and Sheboygan combined area.

Other EGU facilities in the non-attainment counties also undertook actions resulting in decreased NOx emission rates between 1999 and 2002. These actions were primarily aimed at meeting phase II Acid Rain requirements, equipment update needs, or initial equipment installations for anticipated NOx requirements. However, the overall mass of NOx dropped only 2 tons per day due to an increase in unit operation. The 2002 year was a higher than normal utilization year due to hot summer conditions. This demonstrates that even when growth is coupled with a high utilization year, the 6 county area realized a drop in NOx emissions.

NOx Emissions – 2002 to 2018

NOx emissions will continue to decrease significantly beyond 2002 with the majority of reduction occurring by 2007. The total amount of NOx emitted in the analysis region is expected to go down by over 75 tons per day or 40% of 1999 levels. The decrease is even greater if looking at just the core eight non-attainment counties where NOx is projected to decrease by 85 tons per day or 53% of 1999 levels.

Manitowoc County NOx emissions are projected to increase by less than ½ ton per day between 2002 and 2018. However, it is anticipated that actual emissions will not rise or even fall below 2002 levels due to MPU having installed a new fluidized bed generation unit. This unit has additional capacity beyond the analysis growth available through the 2018 time frame. Since the new unit is more efficient it is likely MPU will switch generation from the older more polluting units to the new low emitting unit.

The analysis shows a significant limitation in the amount of potential NOx emissions. The existing coal fired units owned by the private utilities (We-Energies, Alliant, WPS) reach their maximum heat input capacities by 2007. This accounts for nearly all of the coal-fired units in the analysis region or approximately 95% of EGU emissions. Also, these units are all affected by NOx emission limitations by 2007 with the We-Energies Consent Decree implementing deeper limitations through 2015. The combined cycle capacity similarly reaches maximum capacity by 2010. Therefore the analysis demonstrates maximum potential for nearly all EGU NOx emission sources in the region.

The analysis indicates NOx emission by new coal generation starting after 2010 with approximately 2.5 tons per day by 2015 and 4.8 tons per day by 2018. This is roughly equivalent to 1,000 megawatts of capacity in 2015 and 2,000 megawatts in 2018. This estimate is consistent with We-energies Power-the-Future initiative to have 1,200 megawatts of new coal capacity available by 2010.

Analysis Factors Supporting a Conservative Emissions Estimate

The analysis results in a conservatively high projection of NOx emitted by the regional electric utility sector. This expectation is based on a number of factors:

1) As stated, the 2002 baseline year saw elevated unit operation due to hotter than normal summer conditions.

2) The growth rate of 2.7% representing electricity demand is assumed to represent growth in summer electricity consumption.
3) Growth is applied in hierarchy of highest emitting source types for baseload electricity consumption (existing coal, existing combined cycle, new coal).
4) Relatively high capacity factors are assumed for the medium to small coal fired units in the region. This results in growth allocated to existing coal units longer than expected rather than going to the next hierarchy of cleaner units.
5) It is expected existing coal units will be retired and replaced with cleaner capacity by the 2015 to 2018 timeframe.
6) The utilities could potentially utilize capacity outside of the analysis region. However all growth beyond the region units is allocated to new coal generation in the region. Also, it is likely new generation will be a combination of coal and cleaner combined cycle units.

Table 1. Electric Utility Ozone Precursor Emissions and Projections

Sub-Region			**NOx (TPOSD)**						**VOC (TPOSD)**					
County	**County ID**		**1999**	**2002**	**2007**	**2009**	**2015**	**2018**	**1999**	**2002**	**2007**	**2009**	**2015**	**2018**
Manitowoc & Sheboygan														
Manitowoc	55071		2.5	3.5	3.5	3.5	3.8	3.9	0.09	0.10	0.13	0.14	0.16	0.17
Sheboygan	55117		47.9	25.2	28.7	27.8	27.8	27.8	0.18	0.19	0.23	0.23	0.23	0.23
		subtotal =	**50.4**	**28.7**	**32.2**	**31.3**	**31.6**	**31.7**	**0.27**	**0.29**	**0.36**	**0.37**	**0.39**	**0.40**
Six Non-Attainment County Area														
Kenosha	55059		58.8	67.4	14.8	14.8	14.9	14.9	0.76	0.81	0.84	0.84	0.85	0.85
Racine			-	-	-	-	-	-	-	-	-	-	-	-
Milwaukee	55079		43.5	33.2	33.3	33.3	26.8	26.8	1.85	1.99	2.34	2.34	2.34	2.34
Ozaukee	55089		6.7	6.1	0.4	0.5	0.7	0.7	0.23	0.25	0.16	0.21	0.28	0.28
Washington	55131		1.1	1.1	1.3	1.3	1.5	1.6	0.04	0.05	0.05	0.06	0.06	0.07
Waukesha			-	-	-	-	-	-	-	-	-	-	-	-
		subtotal =	**110.0**	**107.8**	**49.8**	**50.0**	**43.9**	**44.0**	**2.88**	**3.10**	**3.39**	**3.45**	**3.53**	**3.54**
Downwind Non-Attainment County Area														
Kewaunee	55061		-	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
Door			-	-	-	-	-	-	-	-	-	-	-	-
		subtotal =	**-**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
EGU Capacity in Adjacent Attainment Area														
Brown	55009		21.7	24.2	26.0	26.2	26.4	26.4	0.85	0.93	1.00	1.01	1.03	1.03
Outagamie	55087		-	0.0	0.2	0.3	0.4	0.4	-	0.00	0.01	0.01	0.01	0.01
Fond dul Lac	55039		0.9	0.2	0.2	0.2	0.2	0.2	0.00	0.00	0.00	0.00	0.01	0.01
Winnebago	55139		0.2	0.4	0.5	0.6	0.8	0.8	-	0.00	0.01	0.01	0.01	0.01
		subtotal =	**22.8**	**24.8**	**26.9**	**27.3**	**27.7**	**27.8**	**0.85**	**0.94**	**1.02**	**1.04**	**1.06**	**1.06**
New Coal	**Regional**						2.5	4.8		-	-	-	0.18	0.34
8 County Non-Attainment Area			**160.4**	**136.5**	**82.0**	**81.3**	**75.5**	**75.7**	**3.2**	**3.4**	**3.8**	**3.8**	**3.9**	**3.9**
		Change from 1999 Emissions (TPD) =		(23.9)	(78.4)	(79.1)	(84.9)	(84.7)		0.2	0.6	0.7	0.8	0.8
		Percent Change from 1999 Emissions =		-15%	-49%	-49%	-53%	-53%		8%	19%	21%	24%	25%
Non-attainment County Area			**160.4**	**136.5**	**82.0**	**81.3**	**75.5**	**75.7**	**3.2**	**3.4**	**3.8**	**3.8**	**3.9**	**3.9**
		Change from 1999 Emissions (TPD) =		(23.9)	(78.4)	(79.1)	(84.9)	(84.7)		0.2	0.6	0.7	0.8	0.8
		Percent Change from 1999 Emissions =		-15%	-49%	-49%	-53%	-53%		8%	19%	21%	24%	25%
Total Analysis Region			**183.2**	**161.3**	**108.9**	**108.6**	**105.7**	**108.3**	**4.0**	**4.3**	**4.8**	**4.9**	**5.2**	**5.3**
		Change from 1999 Emissions (TPD) =		(21.9)	(74.3)	(74.6)	(77.5)	(74.9)		0.3	0.8	0.9	1.2	1.3
		Percent Change from 1999 Emissions =		-12%	-41%	-41%	-42%	-41%		8%	19%	21%	29%	34%

References

1) EPA, Air Markets Program, *Ozone Season: NOx Value 1999 , 2002,* http://www.epa.gov/airmarkets/emissions/prelimarp/index.html, January 2005.

2) Wisconsin Public Service Commission, *Wisconsin's Strategic Energy Assessment*, Final Report – September 2004, Docket 05-ES-102.

3) Wisconsin Department of Administration, Energy Division, *Wisconsin Energy Statistics – 2004*, January 2005.

Attachment 1. Summary of Electric Utility Emissions by Facility

Table A1. Summary of Electric Utility Facility NOx Emissions

Existing Facilities	FIP	County	1999	2002	2007	2009	2015	2018
De-Pere Energy Center	405170920	Brown	-	0.3	0.5	0.7	0.9	0.9
JP Pulliam	405031990	Brown	21.7	23.9	25.5	25.5	25.5	25.5
South Fond Du Lac	420101660	Fon du Lac	0.9	0.2	0.2	0.2	0.2	0.2
Paris	230094810	Kenosha	1.0	0.3	0.4	0.4	0.4	0.4
Pleasant Prairie	230006260	Kenosha	57.8	67.1	14.5	14.5	14.5	14.5
Kewauee - WPS	431022790	Kewaunee	-	0.0	0.0	0.0	0.0	0.0
Manitowoc Public Utilities	436035930	Manitowoc	2.5	3.5	3.4	3.5	3.7	3.9
Point Beach - We	436034500	Manitowoc	0.0	0.0	0.0	0.0	0.0	0.0
Milwaukee Power Plant	241027050	Milwaukee	0.8	0.8	0.8	0.8	0.8	0.8
South Oak Creek	241007690	Milwaukee	31.9	23.8	18.7	18.7	12.2	12.2
Valley	241007800	Milwaukee	10.8	8.6	13.8	13.8	13.8	13.8
Kaukauna Utilities	445033600	Kaukauna	-	0.0	0.0	0.0	0.0	0.0
Port Washinton	246004000	Ozaukee	6.7	6.1	0.4	0.5	0.7	0.7
Edgewater	460033090	Sheboygan	47.9	25.2	28.7	27.8	27.8	27.8
Germantown	267006190	Washington	1.1	1.1	1.3	1.3	1.5	1.6
Menasha Electric & Water	471033640	Winnebago	0.2	0.2	0.2	0.2	0.3	0.3
Mirant Neenah Power Plant	471153870	Winnebago	-	0.2	0.3	0.4	0.5	0.5
New Facilities								
Generic Coal Fired Capacity	NEW	Regional	-	-	-	-	2.5	4.8
Fox Energy	NEW	Kaukana	-	-	0.2	0.3	0.4	0.4
			183.2	**161.3**	**108.9**	**108.6**	**105.7**	**108.3**

Table A2. Summary of Electric Utility Facility VOC Emissions

Existing Facilities	FIP	County	1999	2002	2007	2009	2015	2018
De-Pere Energy Center	405170920	Brown	-	0.0	0.0	0.1	0.1	0.1
JP Pulliam	405031990	Brown	0.8	0.9	1.0	1.0	1.0	1.0
South Fond Du Lac	420101660	Fon du Lac	0.0	0.0	0.0	0.0	0.0	0.0
Paris	230094810	Kenosha	0.0	0.0	0.0	0.0	0.0	0.0
Pleasant Prairie	230006260	Kenosha	0.7	0.8	0.8	0.8	0.8	0.8
Kewauee - WPS	431022790	Kewaunee	0.0	0.0	0.0	0.0	0.0	0.0
Manitowoc Public Utilities	436035930	Manitowoc	0.1	0.1	0.1	0.1	0.2	0.2
Point Beach - We	436034500	Manitowoc	0.0	0.0	0.0	0.0	0.0	0.0
Milwaukee Power Plant	241027050	Milwaukee	-	-	-	-	-	-
South Oak Creek	241007690	Milwaukee	1.6	1.7	1.9	1.9	1.9	1.9
Valley	241007800	Milwaukee	0.3	0.3	0.4	0.4	0.4	0.4
Kaukauna Utilities	445033600	Kaukauna	-	0.0	0.0	0.0	0.0	0.0
Port Washinton	246004000	Ozaukee	0.2	0.3	0.2	0.2	0.3	0.3
Edgewater	460033090	Sheboygan	0.2	0.2	0.2	0.2	0.2	0.2
Germantown	267006190	Washington	0.0	0.0	0.1	0.1	0.1	0.1
Menasha Electric & Water	471033640	Winnebago	-	-	-	-	-	-
Mirant Neenah Power Plant	471153870	Winnebago	-	0.0	0.0	0.0	0.0	0.0
New Facilities								
Generic Coal Fired Capacity	NEW	Regional	-	-	-	-	0.2	0.3
Fox Energy	NEW	Kaukana	-	-	0.0	0.0	0.0	0.0
			4.0	**4.3**	**4.8**	**4.8**	**5.2**	**5.3**